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March 24, 2003

Mary L. Cottrell, Secretary
Department of Telecommunications and Energy
One South Station
Boston, MA 02110

Re: Boston Edison Company d/b/a NSTAR Electric, D.T.E. 02-80A, Responses to Information Requests

Dear Secretary Cottrell:

Enclosed for filing in the above-referenced matter is the response of Boston Edison Company d/b/a NSTAR Electric to the Information Requests set forth on the accompanying list.

Thank you for your attention to this matter.

Sincerely,

Robert N. Werlin / [illegible]

Robert N. Werlin

Enclosures

cc: William Stevens, Hearing Officer
Service List

!

Responses to Information Requests

Information Request DTE-3-1
Information Request DTE-3-2
Information Request DTE-3-7
Information Request DTE-3-8
Information Request DTE-3-9
Information Request DTE-3-10
Information Request DTE-3-11
Information Request DTE-3-12
Information Request DTE-3-13
Information Request DTE-3-14

March 24, 2003

Information Request DTE-3-1

Please provide the following for all purchased power contracts that were used to supply BECo's standard offer service load during calendar year 2002: the name of the supplier, the effective date and the closing date, and BECo's entitlement.

Response

The following table contains the requested information applicable to Boston Edison Company.

Supplier (Unit)	**Effective date**	**Closing Date**	**BEC entitlement (Mw)**
Mirant (Canal 1)	January 1, 1999	October 10, 2002	139.75 Summer 141.50 Winter
OSP 1	December 31, 1990	December 31, 2010	62.04 Summer 72.85 Winter
OSP 2	October 1, 1991	September 30, 2011	62.57 Summer 72.85 Winter
NEA 1	September 15, 1991	September 15, 2016	135.0
NEA 2	September 15, 1991	September 15, 2011	68.0 Summer 92.0 Winter
MASSPOWER	January 1, 1994	December 31, 2013	100.0 Summer 117.0 Winter
MBTA Jet 1	June 1, 1986	December 31, 2005	25.0 Summer 33.4 Winter
MBTA Jet 2	May 1, 1994	December 31, 2019	25.0 Summer 34.7 Winter
Entergy (Pilgrim)	November 18, 1998	December 31, 2004	393.1
Entergy (Pilgrim – Munis)	November 18, 1998	December 31, 2004	25.0
AEP	April 6, 2001	Open ended	41.917
Constellation	January 15, 1998	Open ended	41.917
Constellation	January 1, 2002	December 31, 2002	Load following
Fringe (various)			
PGE	July 18, 2000	Open ended	41.917
Wentworth	November 29, 1989	Open ended	PUPRA contract

Information Request DTE-3-2

Please provide the following for all purchased power contracts that will be used to supply BECo's standard offer service load during calendar year 2003: the name of the supplier, the effective date and the closing date, and BECo's entitlement.

Response

The following table contains the requested information applicable to Boston Edison Company.

Supplier (Unit)	**Effective date**	**Closing Date**	**BEC entitlement (Mw)**
OSP 1	December 31, 1990	December 31, 2010	62.04 Summer 72.85 Winter
OSP 2	October 31, 1991	September 30, 2011	62.57 Summer 72.85 Winter
NEA 1	September 15, 1991	September 15, 2016	135.0
NEA 2	September 15, 1991	September 15, 2011	68.0 Summer 92.0 Winter
MASSPOWER	January 1, 1994	December 31, 2013	100.0 Summer 117.0 Winter
MBTA Jet 1	June 1, 1986	December 31, 2005	25.0 Summer 33.4 Winter
MBTA Jet 2	May 1, 1994	December 31, 2019	25.0 Summer 34.7 Winter
Entergy (Pilgrim)	November 18, 1998	December 31, 2004	236.3
Entergy (Pilgrim Munis)	November 18, 1998	December 31, 2004	25.0
Constellation	January 1, 2003	December 31, 2003	Load following
Fringe (various)			
Wentworth	November 29, 1989	Open ended	PURPA contract

Information Request DTE-3-7

Please provide in a table for the years 2002 and 2003, BECo's estimated and actual transmission expense, the allocator used to collect the expense from each rate class, the percentage of the transmission expense allocated to each rate class, each rate class's forecasted and actual kilowatthour sales, revenues collected from each rate class, and each rate class's transmission charge.

Response

Please refer to Attachment DTE-3-7. The Company allocates the estimated transmission expense to rate class each year by updating its initial unbundled rate class transmission rates from March 1, 1998 by the ratio of the estimated current year average rate level to the 1998 average rate level. The initial transmission rates for each rate class were based upon an historical cost allocation study. The percentage allocation to each rate class based on that study is set forth in the attachment. This allocation percentage is the same for each year. The actual transmission expense recovered in a particular year is a function of the updated rates and the actual billing quantities in that year. The attachment sets forth the actual kWh and transmission revenue for each rate class for 2002. The attachment also lists the forecasted kWh and estimated transmission expense in total for years 2002 and 2003.

Boston Edison
Transmission Rate Development

Rate Schedule	Rates 03/01/1998	Rates 01/01/2002	1995 kWh	Allocated Revenue	Percent Allocation	Actual 2002 kWh	2002 Transmission Revenue
R-1	0.00244	0.00645	2,846,987,874	$ 18,363,072	22.10%	3,391,451,732	$ 21,679,247
R-2(like R-1)	0.00242	0.00640	128,447,190	$ 822,062	0.99%	163,929,175	$ 1,039,953
R-2(like R-3)	0.00242	0.00640	22,725,839	$ 145,445	0.18%	21,632,121	$ 136,456
R-3	0.00241	0.00637	518,448,900	$ 3,302,519	3.97%	483,962,558	$ 3,043,443
R-4	0.00242	0.00640	2,064,647	$ 13,214	0.02%	2,269,368	$ 15,382
G-1(wo dmd)	0.00314	0.00830	349,323,993	$ 2,899,389	3.49%	423,544,592	$ 3,493,991
G-1(w dmd)	0.00314	0.00830	131,282,929	$ 1,089,648	1.31%	156,578,839	$ 1,516,777
G-2	0.00284	0.00751	2,382,967,598	$ 17,896,087	21.54%	2,666,735,549	$ 18,736,163
G-3	0.00227	0.00600	2,707,411,279	$ 16,244,468	19.55%	3,256,524,805	$ 19,221,677
T-1	0.00179	0.00473	123,177	$ 583	0.00%	103,621	$ 463
T-2	0.00245	0.00648	3,271,138,977	$ 21,196,981	25.51%	3,793,194,145	$ 23,762,652
S-1	0.00199	0.00526	83,448,228	$ 438,938	0.53%	50,955,139	$ 243,749
S-2	0.00162	0.00428	52,361,898	$ 224,109	0.27%	97,912,868	$ 413,557
S-3	0.00175	0.00463	18,494,520	$ 85,630	0.10%	21,712,197	$ 101,707
WR	0.00122	0.00323	112,050,928	$ 361,924	0.44%	126,292,800	$ 50,004
Contracts						3,324,152	$ 14,536
Average	0.00250	0.00661	12,627,277,977	$ 83,084,068	100.00%	14,660,123,661	$ 93,469,757
Forecasted						14,826,000,000	$ 97,965,000

Rate Schedule	Rates 03/01/1998	Rates 01/01/2003	1995 kWh	Allocated Revenue	Percent Allocation	Actual 2003 kWh	2003 Transmission Revenue
R-1	0.00244	0.00733	2,846,987,874	$ 20,868,421	22.11%		
R-2(like R-1)	0.00242	0.00727	128,447,190	$ 933,811	0.99%		
R-2(like R-3)	0.00242	0.00727	22,725,839	$ 165,217	0.18%		
R-3	0.00241	0.00724	518,448,900	$ 3,753,570	3.98%		
R-4	0.00242	0.00727	2,064,647	$ 15,010	0.02%		
G-1(wo dmd)	0.00314	0.00943	349,323,993	$ 3,294,125	3.49%		
G-1(w dmd)	0.00314	0.00943	131,282,929	$ 1,237,998	1.31%		
G-2	0.00284	0.00853	2,382,967,598	$ 20,326,714	21.53%		
G-3	0.00227	0.00682	2,707,411,279	$ 18,464,545	19.56%		
T-1	0.00179	0.00538	123,177	$ 663	0.00%		
T-2	0.00245	0.00736	3,271,138,977	$ 24,075,583	25.50%		
S-1	0.00199	0.00598	83,448,228	$ 499,020	0.53%		
S-2	0.00162	0.00487	52,361,898	$ 255,002	0.27%		
S-3	0.00175	0.00526	18,494,520	$ 97,281	0.10%		
WR	0.00122	0.00367	112,050,928	$ 411,227	0.44%		
Contracts							
Average	0.00250	0.00751	12,627,277,977	$ 94,398,187	100.00%		
Forecasted						14,668,919,000	$ 110,125,000

Information Request DTE-3-8

Please list the Federal Energy Regulatory Commission approved tariffs under which BECo receives transmission service on behalf of its customers. For each tariff listed provide: (a) a description of the services provided under the tariff,(b) the expenses billed to Boston Edison under the tariff for calendar year 2002, and (c) for Boston Edison's Open Access Transmission Tariff a copy of the Company's most recent filing to the FERC and a copy of FERC's decision.

Response

The FERC approved Tariffs under which Boston Edison receives transmission service on behalf of its customers are listed as follows:

1) Boston Edison Open Access Transmission Tariff
2) NEPOOL Open Access Transmission Tariff
3) ISO-NE Tariff

1a) Generally, the Boston Edison Open Access Transmission Tariff provides for Local Network Integration Service, Point-to-Point Transmission service, Transmission service over High Voltage Direct Current Facilities, and Scheduling, System Control and Dispatch Service.

1b) The transmission expenses billed to Boston Edison under the Boston Edison Open Access Transmission Tariff for the calendar year 2002 is provided in Exh. BEC-JFL-3. Please refer to the response to Information Request DTE –3-6 for a detailed explanation of the expenses billed under the tariff.

2a) Generally, the NEPOOL Open Access Transmission Tariff provides for Regional Network Service, Through or Out Service, Congestion Management Services, an Uplift charge with respect to excepted transactions, and certain Ancillary Services to maintain reliability.

2b) The transmission expenses billed to Boston Edison under the NEPOOL Open Access Transmission Tariff for the calendar year 2002 is provided in Exh. BEC-JFL-3. Please refer to the response to Information Request DTE–3-6 for a detailed explanation of the expenses billed under the tariff.

3a) Generally, the ISO-NE Tariff provides for Transmission Dispatch and Power Administration services. The transmission related expense is the Transmission Dispatch or the ISO System Control, Scheduling and Dispatch. The Power Administration services are generation related expenses.

3b) The transmission expenses billed to Boston Edison under the ISO-NE Tariff for the calendar year 2002 is provided in Exh. BEC-JFL-3. Please refer to the response to Information Request DTE–3-6 for a detailed explanation of the expenses billed under the Tariff.

With respect to Boston Edison's Open Access Transmission Tariff, Attachments DTE 3-8(a) and DTE 3-8(b) set forth the most recent filing and resulting FERC Order, respectively.

D.T.E. 02-80A
Attachment DTE-3-8(a)

NSTAR SERVICES CO.

800 Boylston Street
Boston, Massachusetts 02199

Mary E. Grover, Esq.
Direct Dial: (617) 424-3804
Facsimile: (617) 424-2733
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FEDERAL ENERGY
REGULATORY
COMMISSION

The NSTAR Companies
Boston Edison
ComElectric
ComGas
Cambridge Electric

March 31, 2000

ORIGINAL

Honorable David P. Boergers
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

ER00-2065-000

Re: Boston Edison Company; Open Access Transmission Tariff, Docket No. ER00-

Dear Secretary Boergers:

Pursuant to Section 205 of the Federal Power Act and Part 35 of the Commission's regulations under the Act, 18 C.F.R. Part 35, Boston Edison Company ("BECo") hereby submits for filing an original and five (5) copies of revised tariff sheets effecting a change to its Open Access Transmission Tariff ("Tariff") to implement revised billing and payment provisions that will allow BECo to recover its transmission costs on a more timely basis. BECo requests that the proposed changes be made effective on June 1, 2000.

General Description of Filing

BECo, a wholly-owned subsidiary of NSTAR and an affiliate of Cambridge Electric Light Company and Commonwealth Electric Company, owns and operates an electric transmission system in Boston and its surrounding communities. BECo has traditionally billed its transmission customers under the Tariff using costs reflective of a historical period of time. Depending on the billing month, a customer could be billed based upon costs incurred by BECo as much as 17 months earlier. As the Tariff currently exists, there is no true-up mechanism which would allow BECo to ultimately recover all its costs from, or refund any over-collections to its customers.

Given the current environment of increasing transmission costs due to the substantial rise in construction of new transmission facilities, attributable in large part to electric restructuring in Massachusetts and the resulting competitive generation market which requires new transmission facilities to support a growing number of generation units, BECo is experiencing a revenue shortfall, a situation which is not expected to change in the foreseeable future. To remedy this problem, BECo is proposing to change the billing procedure contained in Section 7.1 of the Tariff to include provisions allowing BECo to render billings based on cost estimates for the Service Year. In addition, those billings would be subject to an annual true-up when the actual costs for the Service

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Year are known. Other modifications to the Tariff to implement the change in billing procedure are as follows:

- Two definitions were added to Section 1: Annual True-Up and Service Year.
- Section 34, Rates and Charges, was expanded to include a paragraph describing the billing based on estimates with an annual true-up.
- Schedule 1, Scheduling, System Control and Dispatch Service, was modified slightly to state that revenue requirements will be computed using costs from the Service Year.
- Attachment H, Annual Transmission Revenue Requirement, was also modified to state that revenue requirements will be computed using costs from the Service Year.

List of Materials Enclosed

The following is a list of documents submitted with this filing:

- Exhibit BE-1, Testimony of Rose Ann Pelletier explaining the filing, the modification to the billing procedure, and the reasons for the proposed changes. Attachments to Ms. Pelletier's testimony illustrate the revised methodology and the resulting billing impacts to each wholesale transmission customer of BECo.
- Exhibit BE-2, Revised clean tariff sheets tendered for filing.
- Exhibit BE-3, Existing tariff sheets redlined to show changes.
- A form of notice suitable for publication in the Federal Register in accordance with Section 35.8 of the Commission's regulations.
- Certification of service.

Notice and Correspondence

BECo requests that all communications regarding this filing be directed to the following individuals and that their names be entered on the official service list maintained by the Secretary:

Mary E. Grover, Esq.
NSTAR Services Company
800 Boylston Street, P-170
Boston, MA 02199-8003
Phone: (617) 424-3804
Fax: (617) 424-2733

Kevin Walsh
NSTAR Services Company
800 Boylston Street, P1603
Boston, MA 02199-8003
Phone: (617) 424-3373
Fax: (617) 424-3472

Service

A copy of this filing has been served upon the persons named on the enclosed Certificate of Service.

Waiver

BECo requests waiver by the Commission of any requirements of the Commission's rules and regulations, as well as any authorizations as may be necessary or required to permit these Tariff sheets to be accepted by the Commission and made effective in the manner proposed herein.

No costs to be recovered by this filing have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices.

Conclusion

BECo respectfully requests that the Commission accept these proposed Tariff changes and permit them to take effect without suspension, condition or modification, as of June 1, 2000.

Should additional information be required, please contact the undersigned. Also, please acknowledge receipt of the enclosed materials by date stamping and returning the extra copy of this filing in the enclosed self-addressed, postage pre-paid envelope. Thank you.

Respectfully submitted,

Mary E. Grover

Mary E. Grover
Attorney for Boston Edison Company

Enclosures

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Exhibit BE-1

Testimony of Rose Ann Pelletier

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Boston Edison Company) **Docket No. ER00-_______**

DIRECT TESTIMONY OF ROSE ANN PELLETIER ON BEHALF OF BOSTON EDISON COMPANY

Q. **Ms. Pelletier, please state your name and business address.**

A. My name is Rose Ann Pelletier. My business address is 800 Boylston Street, Boston, Massachusetts.

Q. **By whom are you employed and in what capacity?**

A. Currently, I am Director of Transmission and Power Contract Administration for NSTAR Services Company. In that capacity, I am responsible for the coordinating and managing issues associated with power and transmission purchase and sales contracts for Boston Edison Company.

Q. **Please describe your educational background and business experience.**

A. I graduated from Providence College in 1977 earning a Bachelor's degree in Economics and from Boston College in 1979 with a Master's in Economics. In 1980, I joined Boston Edison as a research analyst in the rates department. Subsequently I have held positions as Fuel Rate Analyst, Fuel Rate Administrator, Fuel Rate and Unit Performance Administrator and Manager of Power Contracts.

Q. **Have you previously testified in regulatory proceedings?**

A. Yes. I have testified before this Commission regarding Boston Edison's wholesale fuel adjustment clause. In addition, I have testified in a number of proceedings before the Massachusetts Department of Telecommunications and Energy in support of Boston Edison's periodic fuel adjustment clause and performance review proceedings.

Q. **What is the purpose of your testimony?**

A. The purpose of this testimony is to provide support for the Company's request for approval to modify the billing and payment provisions set forth in Sections 7.1

and 34, Schedule 1 and Attachment H under Boston Edison's Open Access Transmission Tariff (Tariff) to include additional terms and conditions that allow the Company to recover its transmission costs from its customers on a more timely basis.

Q. Why is this change necessary?

A. The change is necessary to correct a deficiency in the way Boston Edison determines its billings for its customers. Under the existing Tariff, the transmission rates that are applicable for billing customers using network and point-to-point transmission service in any particular month reflect costs from a historical time period. Consequently, the rates are not reflective of the current cost conditions at the time the customers are billed. Accordingly, in an environment of increasing costs (which exists today for Boston Edison and most of New England) the current tariff design guarantees that there will be a revenue shortfall. Exacerbating this problem is that the existing billing provision does not contain a true-up clause to include a full reconciliation and adjustment for any over or under recoveries occurring under the prior year's billings.

Q. Please explain and support your statement that Boston Edison is in an increasing cost environment.

A. Boston Edison will incur a substantial investment in its transmission system in the near-term for reliability and congestion relief purposes. Attachment 1 illustrates a two-year annual forecast of the transmission capital investments the Company will incur by project name and category type. Clearly, a significant infusion of capital must be made to maintain Boston Edison's transmission system at an operational level that is efficient and effective.

Q. What factors contribute to this increasing cost environment?

A. Increased load growth, transmission constraints and interconnectivity of generators to the transmission system are all contributing factors in Boston Edison's transmission growth and its associated capital increases. Furthermore, as a result of deregulation, Boston Edison has divested itself of all its holdings in its generation assets and is exiting the business of providing generation services entirely over time, in accordance with the provisions of the Massachusetts Electric Restructuring Act.. Consequently, it cannot rely on installing generation units or purchasing power as an alternative method to fortifying its transmission system in providing added reliability and congestion relief where needed as it was able to do under its vertically integrated business prior to deregulation. Thus more contributions have to be made for transmission investments.

Q. How does the Company propose to implement the billing provisions in practice?

A. Essentially, the implementation of the change in the billing provisions will require a two-tier approach in the cost recovery process. First, the customers' bills will reflect rates that are estimated on the basis of projections of costs that are commensurate with the time the customer is receiving its service. This is necessary in matching revenues more closely with cost incurrence. Second, once the actual costs for a calendar year period are known, the estimated projected costs used for the monthly billing periods within the calendar year period will be reconciled to ensure that true costs are being recovered.

Q. Please describe how the Company's determination of cost projections for billing purposes will differ from that which is currently in effect.

A. Under the billing provisions currently in effect, the customers' monthly bills starting in June, 2000 would reflect rates based upon the previously approved transmission cost of service formula during the 1999 calendar year period. The monthly billings on this cost basis would continue beyond the year 2000 until May, 2001 inclusive. Going forward, the June, 2001 to May, 2002 billings would be based upon rates reflective of costs during the calendar year 2000 thus repeating the billing cycle cost relationship. Thus, a billing/cost examination of the calendar year 2001 reveals that January through May's billings are based upon the calendar year 1999 transmission cost of service while the June through December's billings are based upon the calendar year 2000 transmission cost of service. And, since the Tariff currently does not contain any true-up mechanism, the customers' bills are never adjusted to reflect the actual costs incurred during the billing period.

Under, the proposed billing provisions, the June 2000 through May 2001 billings would be based upon projected cost estimates. However, the historical 1999 calendar year data will still serve as the cornerstone in the development of the estimated costs. The 1999 calendar year actual costs will be added to a forecast of the incremental transmission cost of service for the calendar years 2000 and 2001. Using this approach, customers' monthly bills for the June, 2000 through May, 2001 billing period would be based on an estimate of actual transmission costs incurred by Boston Edison during this time period. For billings occurring in the next billing period from June, 2001 through May, 2002, the actual transmission cost of service for the year 2000 will then be the starting point for the projections.

Q. **Please provide details regarding the manner in which the Company has projected the years 2000 and 2001 transmission cost of service corresponding to each of the 12 monthly billing periods mentioned above.**

A. As set forth in Attachment 2, incremental revenue requirements reflecting projected years 2000 and 2001 capital cost additions (net of retirements) were calculated. The fixed charge rate that was applied to the cost additions in each year to derive the revenue requirement was based upon the ratio of Boston Edison's 1999 total transmission system cost of service (with certain exclusions) to the total transmission investment (net of SCADA-related investments) in effect at year's end 1999. Attachment 2 to my testimony illustrates this calculation. As shown in Attachment 3, the incremental revenue requirement for year 2000 was then added to the 1999 actual transmission cost of service to derive the estimated 2000 transmission cost of service. Similarly, for the year 2001, an incremental revenue requirement associated with the projected year 2001 capital cost additions was determined and subsequently added to the 2000 transmission cost of service to derive the estimated 2001 transmission cost of service.

Q. **What exclusions do you refer to in your fixed charge calculation and why are they appropriate?**

A. The exclusions refer to expenses incurred for support and wheeling by other parties and any revenues received by the Company for providing such services as applicable for the 1999 service year. These expenses and revenues were excluded because they reflect grandfathered type contracts reminiscent of the prior regime in which transmission service was administered. Going forward, with open access of the transmission system as required under Order 888, contracts of this nature will no longer be provided. Thus, these types of expenses and revenues are not conducive to the process of projecting costs. In addition, Schedule 1-SCADA-related costs have been removed from the calculation since these ancillary costs are treated separately in the Tariff.

Q. Are there any other projections involved in calculating the local transmission rates administered under the Tariff?

A. Yes, since the local network and point-to-point rates reflect the total Boston Edison transmission system cost of service less any revenues received from other sources, it follows that revenues received by the Company must also be projected. The Company receives revenues from ISO New England in the form of Regional Network Revenues (RNS) and Through-or-Out Revenues which are credited against the transmission cost of service in developing the local network and point-to-point rates. Since a substantial portion of the RNS revenues are affected by a phase-in approach, it is critical to project this revenue credit as accurately as possible in the rate calculations. Attachment 4 illustrates the RNS revenue development for the applicable billing years. (see KTW's addition)

Q. Does the Company propose to project Schedule 1, SCADA-related costs?

A. If capital cost additions associated with SCADA can be identified for the prospective time periods then the associated incremental revenue requirements will be factored in the projection. Since none have been identified for the 2000 and 2001 calendar year time period, the estimated SCADA-related costs for the 12 monthly billing periods culminating June 2000 through May 2001 will reflect historical 1999 costs only.

Q. What is the bill impact to the wholesale customers who receive service under the Tariff?

A. Attachment 5 shows the effect of the billing impact to the transmission customers taking service under the Tariff for the 12 monthly billing periods from June 2000 through May 2001. A comparison was made to show the difference between the existing revenues and the proposed revenues attributable to each transmission customer. The composite difference in revenues is also shown.

Q. Is this increase really a change in the Company's rate?

A. No, the Company is not proposing a change in its rate. The components of the formula cost of service remain intact with no increase to the ROE or inclusion (or exclusion) of any additional items that comprise the rate base or cost of service portion of the formula.

Q. Are you aware of any other transmission providers who have similar billing provisions in their transmission tariffs?

A. Yes. Boston Edison's affiliates, Cambridge Electric Light Company and Commonwealth Electric Company, and New England Power Company all have similar provisions in their local open access transmission tariffs.

Q. Do you have anything further to add?

A. Yes, the projected cost of service will more closely match the Company's cost incurrence at the time the customer is receiving service. This is vital to the Company in maintaining revenue stability in the transmission business while still providing reliable service. Also, I wish to point out that the customer is protected against any overzealous cost projections due to the methodical process being followed as well as the inclusion and ultimate implementation of the true-up cost mechanism stipulated in the billing provision amendment. In addition, the true-up to actual costs will continue to cap total billings to all wholesale customers to the amounts agreed to under the settlement agreement in Docket Nos. ER99-978-000 and EL99-31-000.

Q. Does this complete your testimony?

A. Yes it does.

Attachment 1

Boston Edison Company

Determination of Capital Cost Additions

Year = 2000

Project Type and Name	Facility Type	Capital Additions	Retirements	Net Additions
Reliability	PTF			
	(a)	(b)	(c)	(d)
345kv Cable & Auto- Transformer to Kingston St. (#324 Line)		$18,882,755	$0	$18,882,755
345kv Relay Upgrade		$1,770,258	$0	$1,770,258
Total		$20,653,014	$0.	$20,653,014
Congestion Relief	PTF			
BECO Uplift/High Voltage Relief - Add Reactors		$3,894,568	$0	$3,894,568
Framingham - Needham 115kv Line Reconductoring (#240-#510)		$2,478,362	$466,011	$2,012,351
Needham - West Walpole 115kv Resag (#148-#522 Line)		$3,658,534	$265,000	$3,393,534
Total		$10,031,464	$731,011	$9,300,453
Grand Total		$30,684,477	$731,011	$29,953,466

Determination of Capital Cost Additions

Year = 2001

Project Type and Name	Facility Type	Capital Additions	Retirements	Net Additions
Reliability	PTF			
Waltham - Sudbury 115kv Line Reconductoring (#280-#507)		$2,478,362	$0	$2,478,362
Misc Transmission Capital Refurbishment		$1,180,172	$0	$1,180,172
Total		$3,658,534	$0	$3,658,534
Congestion Relief	PTF			
Voltage Control (Add two 115kv Reactors)		$4,130,603	$0	$4,130,603
NEMA Import Relief (1): Dewars Street Phase Shifters		$8,261,205	$0	$8,261,205
NEMA Import Relief (1): Needham - Baker Strret Terminal Upgrade		$2,360,344	$0	$2,360,344
Total		$14,752,153	$0	$14,752,153
Grand Total		$18,410,686	$0	$18,410,686

Attachment 2

Boston Edison Company
Determination of the Fixed Charge Rate and Incremental Transmission Revenue Requirement

Fixed Charge Rate Calculation (1999 data)

	Transmission Cost of Service	
1	Investment Return and Income Taxes	$28,526,590
2	Depreciation Expense	$7,382,013
3	Amortization of Loss on Reacquired Debt	$0
4	Investment Tax Credit	-$626,082
5	Property Taxes	$8,584,748
6	Payroll Taxes	$262,046
7	Operation & Maintenance Expense (inc Support expenses)	$13,317,912
8	Administrative & General Expenses	$2,473,124
9	Support expenses (credit)	-$4,456,898
10		
11	Total Transmission Cost of Service (sum of lines 1 thru 9)	$55,463,453
12		
13	Total Transmission Plant (less EMC Scada System cost)	$417,130,462
14		
15	Fixed Charge Rate (based upon 1999 data) (line 11/ line 13)	13.30%
16		
17	Year 2000 Net Capital Additions (from attachment 1, line 14, col. d)	$29,953,466
18		
19	Year 2000 Incremental Revenue Requirement (line 15* line17)	$3,982,741
20		
21	Year 2001 Net Capital Additions (from attachment 1, line 40, col. d)	$18,410,686
22		
23	Year 2001 Incremental Revenue Requirement (line 15* line 21)	$2,447,964

Boston Edison Company
Transmission Revenue Requirement
Projected Years 2000 & 2001 Amounts

		Actual 1999
	INVESTMENT BASE	
1	Transmission Plant (excluding EMC Scada System)	$417,130,462
2	General Plant	$1,490,010
3	Plant Held For Future Use	$0
4	Total Plant (Lines 1+2+3)	$418,620,472
5		
6	Accumulated Depreciation	$161,605,927
7	Accumulated Deferred Income Taxes	$62,300,853
8	Loss on Reacquired Debt	$0
9	Other Regulatory Assets	$11,051,526
10	Net Investment (Lines 4-6-7+8+9)	$205,765,218
11		
12	Prepayments	$2,820,059
13	Materials & Supplies	$384,062
14	Cash Working Capital	$1,973,879
15		
16	Total Investment Base (Lines 10+12+13+14)	$210,943,218
17		
18		
19	REVENUE REQUIREMENT	
20		
21	Investment Return and Income Taxes	$28,526,590
22	Depreciation Expense	$7,382,013
23	Amortization of Loss on Reacquired Debt	$0
24	Investment Tax Credit	-$626,082
25	Property Taxes	$8,584,748
26	Payroll Tax Expense	$262,046
27	Operation & Maintenance Expense	$13,317,912
28	Administrative & General Expense	$2,473,124
29	Transmission Revenue Credit (excl. RNS credits)	-$8,602,446
30		
31	Total 1999 Revenue Requirements (Sum of Lines 21 thu 29)	$51,317,905
32		
33		
34	Projected Year 2000 Incremental Revenue Requirement (from attachment 2, line 19)	$3,982,741
35		
36	Total 2000 Revenue Requirement (Lines 31+34)	$55,300,646
37		
38	Projected Year 2001 Incremental Revenue Requirement (from attachment 2, line 23)	$2,447,964
39		
40	Total 2001 Revenue Requirement (Lines 36+38)	$57,748,610

Note: The revenue requirement which serves the basis for the Local Network Service rates under Boston Edison's Transmission Tariff is equal to the Total Revenue Requirement (as calculated above) less any Regional Network Service revenues received from the ISO New England (as calculated in Attachment 4). The net amount is reflected in Attachments 5(a) and 5(b).

Attachment 4

Boston Edison Company
Determination of Projected RNS revenues received from NEPOOL
Years 2000 & 2001

		Year 2000 Jan-Feb (a)	Year 2000 Mar-May (b)	Year 2000 June-Dec (c)	Year 2000 Total (d)	Year 2001 Jan-Feb (e)	Year 2001 Mar-May (f)	Year 2001 June-Dec (g)	Year 2001 Total (h)
1	NEPOOL Pre-97 PTF Revenue Requirement	$267,786,012	$267,786,012	$267,786,012		$267,786,012	$267,786,012	$267,786,012	
2									
3	BECO Pre-97 PTF Revenue Requirement	$43,431,915	$43,431,915	$43,431,915		$43,431,915	$43,431,915	$43,431,915	
4									
5	NEPOOL MW-Miles	5,001,730	5,001,730	5,001,730		5,001,730	5,001,730	5,001,730	
6									
7	BECO MW-Miles	399,957	399,957	399,957		399,957	399,957	399,957	
8									
9	Phase-In weighing Factors (f2 factor)	0.4808	0.6868	0.6868		0.6868	0.8929	0.8929	
10									
11	% Revenue Requirement weighting	0.85	0.9	0.9		0.9	0.95	0.95	
12									
13	% MW-Miles weighting	0.15	0.1	0.1		0.1	0.05	0.05	
14									
15	Pre-97 PTF Revenues	$19,292,838	$28,317,335	$28,317,335		$28,317,335	$37,795,516	$37,795,516	
16									
17									
18	Post-96 PTF Revenues	$1,157,384	$1,157,384	$1,157,384		$1,157,384	$1,157,384	$5,140,125	
19									
20									
21	Total Pre-97 & Post-96 PTF Revenues	$20,450,222	$29,474,719	$29,474,719		$29,474,719	$38,952,900	$42,935,641	
22									
23	Period weighting	0.1667	0.2500	0.5833		0.1667	0.2500	0.5833	
24									
25	Projected Pre-97 & Post-96 PTF Revenues received	$3,408,370	$7,368,680	$17,193,586	$27,970,637	$4,912,453	$9,738,225	$25,045,790	$39,696,469

Note: June 2000 thru May 2001 Post-96 PTF Revenues remains at $1,157,384
The reason is that estimates do not reveal any 1999 PTF additions.

Attachment 5

Boston Edison Company
Open Access Transmission Tariff
Comparison of Existing and Proposed Revenues
June 2000 - May 2001

Line No.	Transmission Customer	(A) Class of Service	(B) Category of Service	(C) Existing Tariff Transmission Revenue (Attachment 5A)	(D) Proposed Tariff Transmission Revenue * (Attachment 5B)	(E) Difference
1	Braintree Municipal Light Department	Wholesale	Network	131,911	164,481	32,570
2						
3	Hingham Municipal Light Department	Wholesale	Network	56,781	70,774	13,993
4						
5	Hull Municipal Light Department	Wholesale	Network	15,882	19,784	3,903
6						
7	New England Power Company	Wholesale	Network	453,253	564,979	111,726
8						
9	Reading Municipal Light Department	Wholesale	Network	203,365	253,729	50,364
10						
11	Boston Edison Company Distribution	Retail	Network	17,775,021	22,438,011	4,662,991
12						
13	Norwood Municipal Light Department	Wholesale	Network	128,384	158,170	29,786
14						
15	Sithe New England	Wholesale	Network	6,804	8,483	1,680
16						
17	Massachusetts Municipal Wholesale Electric Company	Wholesale	Firm pt-pt	41,055	52,180	11,125
18						
19	Total			18,812,455	23,730,592	4,918,138

* The true-up to actual costs the will continue to cap total billings to all wholesale customers at $1.1 million, $.2million, and $.2million for years 4,5 and 6 of the transition period.

Attachment 5A

Boston Edison Company
Estimated Monthly Revenues
June 2000 - May 2001
Existing Tariff

Line No.		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
		Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Total
1	Revenue Requirement (Attachment 3)	51,317,805	51,317,805	51,317,805	51,317,805	51,317,805	51,317,805	51,317,805	51,317,805	51,317,805	51,317,805	51,317,805	51,317,805	
2	RNS revenue rec'd from ISO (Attachment 4)	(27,970,537)	(27,970,537)	(27,970,537)	(27,970,537)	(27,970,537)	(27,970,537)	(27,970,537)	(39,696,369)	(39,696,369)	(39,696,369)	(39,696,369)	(39,696,369)	
3	Net LNS Revenue Requirement	23,347,268	23,347,268	23,347,268	23,347,268	23,347,268	23,347,268	23,347,268	11,621,436	11,621,436	11,621,436	11,621,436	11,621,436	
4														
5	LNS Phase down (60% 3/00-2/01, 80% 3/01 - 2/02)	14,008,361	14,008,361	14,008,361	14,008,361	14,008,361	14,008,361	14,008,361	6,972,862	6,972,862	9,297,148	9,297,148	9,297,148	
6	for PTF connected customers, Non-ptf connected													
7	customers, Retail, picks up the phase down amounts													
8														
9														
10	Braintree													
11	Load Ratio	1.9600%	1.9300%	1.9400%	1.9500%	1.8200%	1.9400%	1.9400%	1.9400%	1.9400%	1.9400%	1.9400%	1.9400%	
12	LNS	37,939	37,650	37,746	37,939	37,366	37,745	37,746	18,788	18,788	18,788	18,788	18,788	367,959
13	Share of LNS Phase down	(22,764)	(22,630)	(22,647)	(22,764)	(22,413)	(22,647)	(22,647)	(11,273)	(11,273)	(15,030)	(15,030)	(15,030)	(226,048)
14	Sch 1													
15	Total	15,176	15,020	15,099	15,176	14,942	15,098	15,099	7,515	7,515	3,758	3,758	3,758	131,911
16														
17	Hingham													
18	Load Ratio	0.8600%	0.8400%	0.8400%	0.8300%	0.8300%	0.8300%	0.8300%	0.8300%	0.8300%	0.8300%	0.8300%	0.8300%	
19	LNS	16,536	16,343	16,343	16,149	16,149	16,149	16,149	8,038	8,038	8,038	8,038	8,038	154,008
20	Share of LNS Phase down	(9,921)	(9,806)	(9,806)	(9,689)	(9,689)	(9,689)	(9,689)	(4,823)	(4,823)	(6,431)	(6,431)	(6,431)	(97,229)
21	Sch 1													
22	Total	6,615	6,537	6,537	6,460	6,460	6,460	6,459	3,215	3,215	1,608	1,608	1,608	56,791
23														
24	Hull													
25	Load Ratio	0.2400%	0.2400%	0.2400%	0.2300%	0.2300%	0.2300%	0.2300%	0.2300%	0.2300%	0.2300%	0.2300%	0.2300%	
26	LNS	4,669	4,669	4,669	4,475	4,475	4,475	4,475	2,227	2,227	2,227	2,227	2,227	43,046
27	Share of LNS Phase down	(2,802)	(2,802)	(2,802)	(2,685)	(2,685)	(2,685)	(2,685)	(1,336)	(1,336)	(1,782)	(1,782)	(1,782)	(27,164)
28	Sch 1													
29	Total	1,868	1,868	1,868	1,790	1,790	1,790	1,790	891	891	445	445	445	15,882
30														
31	NEES													
32	Load Ratio	6.7100%	6.6900%	6.6700%	6.6500%	6.6700%	6.6700%	6.6300%	6.6300%	6.6300%	6.6300%	6.6300%	6.6300%	
33	LNS	130,550	130,161	129,772	129,383	129,772	129,772	128,994	64,209	64,209	64,209	64,209	64,209	1,229,446
34	Share of LNS Phase down	(78,330)	(78,097)	(77,863)	(77,630)	(77,863)	(77,863)	(77,297)	(38,526)	(38,526)	(51,367)	(51,367)	(51,367)	(766,193)
35	Sch 1													
36	Total	52,220	52,064	51,909	51,753	51,909	51,909	51,697	25,683	25,683	12,842	12,842	12,842	463,253
37														
38	Reading													
39	Load Ratio	2.9600%	2.9600%	2.9600%	2.9900%	3.0000%	2.9900%	3.0200%	3.0200%	3.0200%	3.0200%	3.0200%	3.0200%	
40	LNS	57,305	57,590	57,590	58,174	58,368	58,174	58,757	29,247	29,247	29,247	29,247	29,247	582,294
41	Share of LNS Phase down	(34,437)	(34,554)	(34,554)	(34,904)	(35,021)	(34,904)	(35,254)	(17,548)	(17,548)	(23,398)	(23,398)	(23,398)	(348,918)
42	Sch 1													
43	Total	22,868	23,036	23,036	23,270	23,347	23,270	23,503	11,699	11,699	5,849	5,849	5,849	203,386
44														
45	Retail													
46	Load Ratio	83.4400%	83.4600%	83.5000%	83.5100%	83.5300%	83.5600%	83.6000%	83.6000%	83.6000%	83.6000%	83.6000%	83.6000%	
47	LNS	1,628,413	1,623,608	1,634,581	1,634,776	1,635,164	1,636,137	1,636,526	809,027	809,027	809,027	809,027	809,027	16,422,330
48	Share of LNS Phase down	178,318	178,202	168,736	168,851	168,851	168,901	169,384	84,314	84,314	112,418	112,418	112,418	1,604,374
49	Sch 1	54659	54659	54659	54659	54659	54659	54659	54659	54659	54659	54659	54659	655,908
50	Total	1,848,391	1,848,888	1,848,174	1,848,495	1,848,535	1,850,487	1,860,770	948,790	948,790	976,804	976,804	976,804	17,776,021
51														
52	Norwood													
53	Load Ratio	1.7900%	1.8200%	1.7900%	1.8000%	1.7700%	1.7600%	1.7600%	1.7600%	1.7600%	1.7600%	1.7600%	1.7600%	
54	LNS	34,828	35,410	34,828	35,021	34,437	34,243	34,243	17,045	17,045	17,045	17,045	17,045	326,230
55	Share of LNS Phase down	(20,896)	(21,246)	(20,896)	(21,013)	(20,662)	(20,546)	(20,546)	(10,227)	(10,227)	(13,636)	(13,636)	(13,636)	(207,165)
56	Sch 1	3420	3467	3420										7,319
57	Total	16,367	16,631	16,367	14,008	13,775	13,697	13,697	6,818	6,818	3,409	3,409	3,409	126,384
58														
59	Misc													
60	Load Ratio	0.1000%	0.1000%	0.1000%	0.1000%	0.1000%	0.1000%	0.1000%	0.1000%	0.1000%	0.1000%	0.1000%	0.1000%	
61	LNS	1,946	1,946	1,946	1,946	1,946	1,946	1,946	968	968	968	968	968	19,492
62	Share of LNS Phase down	(1,167)	(1,167)	(1,167)	(1,167)	(1,167)	(1,167)	(1,167)	(581)	(581)	(775)	(775)	(775)	(11,689)
63	Sch 1													
64	Total	778	778	779	779	778	778	778	387	387	194	194	194	8,804

Boston Edison Company
Estimated Monthly Revenues
June 2000 - May 2001
Proposed Tariff

Line No.		(A) Jun-00	(B) Jul-00	(C) Aug-00	(D) Sep-00	(E) Oct-00	(F) Nov-00	(G) Dec-00	(H) Jan-01	(I) Feb-01	(J) Mar-01	(K) Apr-01	(L) May-01	(M) Total
1	Revenue Requirement (Attachment 3)	55,300,846	55,300,846	55,300,846	55,300,846	55,300,846	55,300,846	55,300,846	57,748,610	57,748,610	57,748,610	57,748,610	57,748,610	
2	RNS revenue rec'd from ISO (Attachment 4)	(27,970,837)	(27,970,837)	(27,970,837)	(27,970,837)	(27,970,837)	(27,970,837)	(27,970,837)	(38,696,469)	(38,696,469)	(38,696,469)	(38,696,469)	(38,696,469)	
3	Net LNS Revenue Requirement	27,330,009	27,330,009	27,330,009	27,330,009	27,330,009	27,330,009	27,330,009	19,052,141	19,052,141	19,052,141	19,052,141	19,052,141	
4														
5	LNS Phase down (60% 3/00-2/01, 80% 3/01 - 2/02)	16,398,005	16,398,005	16,398,005	16,398,005	16,398,005	16,398,005	16,398,005	10,831,285	10,831,285	14,441,713	14,441,713	14,441,713	
6	for PTF connected customers. Non-ptf connected													
7	customers, Retail, picks up the phase down amounts													
8														
9														
10	Braintree													
11	Load Ratio	1.9500%	1.9300%	1.9400%	1.9500%	1.9200%	1.9400%	1.9400%	1.9400%	1.9400%	1.9400%	1.9400%	1.9400%	
12	LNS	44,411	43,956	44,184	44,411	43,728	44,184	44,184	29,184	29,184	29,184	29,184	29,184	454,878
13	Share of LNS Phase down	(26,647)	(26,373)	(26,510)	(26,647)	(26,237)	(26,510)	(26,510)	(17,511)	(17,511)	(23,347)	(23,347)	(23,347)	(280,498)
14	Sch 1													
15	Total	17,765	17,582	17,673	17,765	17,491	17,673	17,673	11,674	11,674	5,837	5,837	5,837	184,481
16														
17	Hingham													
18	Load Ratio	0.8500%	0.8400%	0.8400%	0.8300%	0.8300%	0.8300%	0.8300%	0.8300%	0.8300%	0.8300%	0.8300%	0.8300%	
19	LNS	19,359	19,131	19,131	18,903	18,903	18,903	18,903	12,469	12,469	12,469	12,469	12,469	195,604
20	Share of LNS Phase down	(11,615)	(11,479)	(11,479)	(11,342)	(11,342)	(11,342)	(11,342)	(7,482)	(7,482)	(9,999)	(9,999)	(9,999)	(124,999)
21	Sch 1													
22	Total	7,744	7,652	7,652	7,561	7,561	7,561	7,561	4,984	4,984	2,497	2,497	2,497	70,774
23														
24	Hull													
25	Load Ratio	0.2400%	0.2400%	0.2400%	0.2300%	0.2300%	0.2300%	0.2300%	0.2300%	0.2300%	0.2300%	0.2300%	0.2300%	
26	LNS	5,466	5,466	5,466	5,238	5,238	5,238	5,238	3,460	3,460	3,460	3,460	3,460	54,651
27	Share of LNS Phase down	(3,280)	(3,280)	(3,280)	(3,143)	(3,143)	(3,143)	(3,143)	(2,076)	(2,076)	(2,768)	(2,768)	(2,768)	(34,867)
28	Sch 1													
29	Total	2,186	2,186	2,186	2,095	2,095	2,095	2,095	1,384	1,384	692	692	692	19,784
30														
31	NEES													
32	Load Ratio	6.7100%	6.6900%	6.6700%	6.6500%	6.6700%	6.6700%	6.6300%	6.6300%	6.6300%	6.6300%	6.6300%	6.6300%	
33	LNS	152,820	152,365	151,909	151,454	151,909	151,909	150,999	99,738	99,738	99,738	99,738	99,738	1,562,055
34	Share of LNS Phase down	(91,692)	(91,419)	(91,145)	(90,872)	(91,145)	(91,145)	(90,599)	(59,843)	(59,843)	(79,790)	(79,790)	(79,790)	(997,079)
35	Sch 1													
36	Total	61,128	60,946	60,764	60,582	60,764	60,764	60,399	39,895	39,895	19,948	19,948	19,948	564,976
37														
38	Reading													
39	Load Ratio	2.9500%	2.9600%	2.9600%	2.9900%	3.0000%	2.9900%	3.0200%	3.0200%	3.0200%	3.0200%	3.0200%	3.0200%	
40	LNS	67,186	67,414	67,414	68,097	68,325	68,097	68,781	45,431	45,431	45,431	45,431	45,431	702,471
41	Share of LNS Phase down	(40,312)	(40,448)	(40,448)	(40,858)	(40,995)	(40,858)	(41,269)	(27,259)	(27,259)	(36,345)	(36,345)	(36,345)	(448,741)
42	Sch 1													
43	Total	26,875	26,966	26,966	27,239	27,330	27,239	27,512	18,172	18,172	9,086	9,086	9,086	253,729
44														
45	Retail													
46	Load Ratio	83.4400%	83.4500%	83.6000%	83.5100%	83.5300%	83.5900%	83.6000%	83.6000%	83.6000%	83.6000%	83.6000%	83.6000%	
47	LNS	1,900,347	1,900,574	1,901,713	1,901,941	1,902,396	1,903,535	1,903,881	1,257,832	1,257,832	1,257,832	1,257,832	1,257,832	19,882,880
48	Share of LNS Phase down	199,372	199,236	199,099	199,626	199,416	199,416	199,276	130,969	130,969	174,624	174,624	174,624	2,177,044
49	Sch 1	54858	54858	54858	54858	54858	54858	54858	54858	54858	54858	54858	54858	658,308
50	Total	2,154,579	2,154,668	2,155,391	2,156,626	2,156,671	2,158,810	2,157,126	1,443,489	1,443,489	1,487,116	1,487,116	1,487,116	22,438,011
51														
52	Norwood													
53	Load Ratio	1.7900%	1.8200%	1.7900%	1.8000%	1.7700%	1.7600%	1.7600%	1.7600%	1.7600%	1.7600%	1.7600%	1.7600%	
54	LNS	40,767	41,451	40,767	40,995	40,312	40,084	40,084	26,476	26,476	26,476	26,476	26,476	418,842
55	Share of LNS Phase down	(24,460)	(24,870)	(24,460)	(24,597)	(24,187)	(24,050)	(24,050)	(15,886)	(15,886)	(21,181)	(21,181)	(21,181)	(266,991)
56	Sch 1	3426	3467	3426										7,318
57	Total	19,733	19,047	19,733	16,398	16,125	16,034	16,034	10,591	10,591	5,295	5,295	5,295	159,170
58														
59	Sithe													
60	Load Ratio	0.1000%	0.1000%	0.1000%	0.1000%	0.1000%	0.1000%	0.1000%	0.1000%	0.1000%	0.1000%	0.1000%	0.1000%	
61	LNS	2,278	2,278	2,278	2,278	2,278	2,278	2,278	1,504	1,504	1,504	1,504	1,504	23,484
62	Share of LNS Phase down	(1,367)	(1,367)	(1,367)	(1,367)	(1,367)	(1,367)	(1,367)	(903)	(903)	(1,203)	(1,203)	(1,203)	(14,981)
63	Sch 1													
64	Total	911	911	911	911	911	911	911	602	602	301	301	301	8,483

COMMONWEALTH OF MASSACHUSETTS ss:

County of Suffolk

Rose Ann Pelletier, being first duly sworn, states:

The forgoing testimony is true and correct to the best of my knowledge, information and belief.

Rose Ann Pelletier

Signed and sworn before me this 29th day of March, 2000

John Cope-Flanagan

Notary Public

My Commission expires: May 26, 2000

Exhibit BE-2

Revised Clean Tariff Sheets

TABLE OF CONTENTS

I. COMMON SERVICE PROVISIONS

1 Definitions

1.1 **Ancillary Services:** Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

1.2 **Annual Transmission Costs:** The total annual cost of the Transmission System for purposes of Network Integration Transmission Service shall be the amount specified in Attachment H until amended by the Transmission Provider or modified by the Commission.

1.2A Annual True-Up: The reconciliation to actual costs of the estimated costs used for billing purposes under Section 7.0 of this Tariff for any Service Year.

1.3 **Application:** A request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

1.4 **Backyard Generation:** Generation which interconnects directly with distribution facilities dedicated solely to load not designated as Network Load. Any distribution facilities which are shared with Network Load will not qualify.

1.5 **Commission:** The Federal Energy Regulatory Commission.

1.6 **Completed Application:** An Application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

1.55A Service Year: The calendar year in which the Transmission Customer is receiving service under this Tariff.

1.56 **Short-Term Firm Local Point-To-Point Transmission Service:** Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of less than one year.

1.57 **System Impact Study:** An assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a request for Firm Point-To-Point Transmission Service, Network Integration Transmission Service or Local Interconnection Service and (ii) whether any additional costs may be incurred in order to provide transmission service.

1.58 **Third-Party Sale:** Any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Network Load under the Network Integration Transmission Service.

1.59 **Transmission Customer:** Any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) for which the Transmission Provider files with the Commission, a proposed unexecuted Service Agreement to receive transmission service under Part II of the Tariff. This term is used in the

Part I Common Service Provisions to include customers receiving transmission service under Part II and Part III of this Tariff.

1.60 **Transmission Provider:** The public utility (or its Designated Agent) that owns, controls, or operates marketer, to request transmission service under the Tariff. If the Transmission Customer does not own, control or operate transmission facilities, it must include in its Application a sworn statement of one of its duly authorized officers or other representatives that the purpose of its Application is not to assist an Eligible Customer to avoid the requirements of this provision.

7 Billing and Payment

7.1 Billing Procedure: Within a reasonable time after the first day of each month, the Transmission Provider shall submit an invoice to the Transmission Customer for the charges for all services furnished under the Tariff during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to the Transmission Provider, or by wire transfer to a bank named by the Transmission Provider.

Billings hereunder shall be based on cost estimates made by the Transmission Provider subject to Annual True-up when actual costs for the Service Year are known. Such Annual True-up shall occur no later than six (6) months after the close of the Service Year to which the Annual True-up relates. Any Annual True-up rendered under this Tariff and any other monthly bill to which the Annual True-up relates shall be binding on both Parties one (1) year from the date of the Transmission Provider's Annual True-up, unless previously disputed pursuant to Section 7.3 of this Tariff.

7.2 **Interest on Unpaid Balances:** Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a (a) (2) (iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bill shall be

Provider, the Transmission Customer shall pay, in addition to any other charges for service, a charge equal to five times the amount of transmission service which the Transmission Customer fails to curtail multiplied by the monthly charge for Firm Point-to-Point Transmission Service.

34 Rates and Charges

Rates for Network Integration Transmission Service shall be determined as set forth in this Section 34 on the basis of estimated costs for each Service Year until the actual costs for such Service Year are determined. Thereafter, payments made on such estimated costs shall be recalculated based on actual data for that Service Year, and all appropriate billing adjustments shall be made pursuant to Section 7 of this Tariff.

The Network Customer shall pay the Transmission Provider for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

34.1 Monthly Demand Charge: The Network Customer shall pay a monthly Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of the Transmission Provider's Annual Transmission Revenue Requirement specified in Attachment H.

34.2 Determination of Network Customer's Monthly Network Load: The Network Customer's monthly Network Load is its hourly load (including its designated Network Load not physically interconnected with the Transmission Provider under Section 31.3) coincident with the Transmission Provider's Monthly Transmission System Peak.

34.3 Determination of Transmission Provider's Monthly Transmission System Load: The Transmission Provider's monthly Transmission System load is the Transmission

SCHEDULE 1

Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Control Area. Service under this schedule represents the contribution to that service provided by Boston Edison's own Dispatch Center, as adjusted for that portion of such allocation received from NEPOOL for BECo's provision of scheduling and dispatch service pursuant to the NEPOOL Open Access Tariff. The Transmission Customer shall pay its Load Ratio Share of Boston Edison's Annual Revenue Requirement for the Scheduling System Control and Dispatch Service on a monthly basis. The Revenue Requirement for the Scheduling System Control and Dispatch Service shall be computed using costs from the Service Year.

Definitions:

Dispatch Center Wages and Salaries Allocation Factor: Ratio of Dispatch Center Related Direct Wages and Salaries to Boston Edison's total Direct Wages and Salaries excluding Administrative and General Wages and Salaries.

ATTACHMENT H

Annual Transmission Revenue Requirement

The Transmission Revenue Requirement will reflect Boston Edison Company's costs for its Transmission System excluding costs associated with Boston Edison's own dispatch center costs which are included in the Schedule 1 revenue requirement. No subtransmission or distribution costs may be included in the Transmission Revenue Requirement. The Transmission Revenue Requirement shall be computed using costs from the Service Year.

Definitions

Transmission Wages and Salaries Allocation Factor: Ratio of Transmission Related Direct Wages and Salaries less Direct Wages of Boston Edison's Dispatch Center included in Schedule 1, to Boston Edison's total Direct Wages and Salaries excluding Administrative and General Wages and Salaries.

Plant Allocation Factor: Ratio of Total Investment in Transmission Plant, excluding Boston Edison's Investment in its own Dispatch Center

Exhibit BE-3

Red-lined Tariff Sheets

TABLE OF CONTENTS

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Definitions

Transmission Wages and Salaries Allocation Factor: Ratio of Transmission Related Direct Wages and Salaries less Direct Wages of Boston Edison's Dispatch Center included in Schedule 1, to Boston Edison's total Direct Wages and Salaries excluding Administrative and General Wages and Salaries.

Plant Allocation Factor: Ratio of Total Investment in Transmission Plant, excluding Boston Edison's Investment in its own Dispatch Center

Notice of Filing

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Boston Edison Company) Docket No. ER00-

NOTICE OF FILING

March __, 2000

Take notice that on March 31, 2000, Boston Edison Company ("BECo") tendered for filing an amendment to its Open Access Transmission Tariff ("Tariff"), which modifies the billing and payment provisions of the Tariff to allow BECo to recover its transmission costs on a more timely basis.

Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. 385.211 and 18 C.F.R. 385.214. All such motions or protests should be filed on or before ____________________, 1999. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection. This filing may also be viewed on the Internet at http://www.ferc.fed.us/online/rims.htm (call 202-208-2222 for assistance).

David Boergers
Secretary

Certificate of Service

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon the following persons:

Malcolm McDonald
Norwood Municipal Light Department
206 Central Street
Norwood, MA 02062-3567

Masheed Rosenqvist
New England Power Company
25 Research Drive
Westborough, MA 01582-0010

Thomas Meineke
Sithe New England
173 Alford Street
Charlestown, MA 02129

Jane Parenteau
Reading Municipal Light Department
P.O. Box 150, 230 Ash Street
Reading, MA 01867-0030

Laurie Heffron
Braintree Electric Light Department
150 Potter Road
Braintree, MA 02184

Joseph Spadea, Jr.
Hingham Municipal Lighting Plant
19 Elm Street
Hingham, MA 02043

John Macleod
Hull Municipal Lighting Plant
15 Edgewater Road
Hull, MA 02045-2714

Massachusetts Department of
Telecommunications and Energy
One South Station, Second Floor
Boston, MA 02110

Dated at Boston, Massachusetts this 31st day of March, 2000.

Mary E. Grover

Mary E. Grover, Esq.
NSTAR Services Company
800 Boylston Street, P170
Boston , MA 02199-8003
(617) 424-3804

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D.T.E. 02-80A
Attachment DTE-3-8(b)

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: James J. Hoecker, Chairman;
William L. Massey, Linda Breathitt,
and Curt Hébert, Jr.

Boston Edison Company — Docket No. ER00-2065-000

ORDER ACCEPTING FOR FILING PROPOSED RATE,
AS MODIFIED, WITHOUT SUSPENSION OR HEARING

(Issued May 31, 2000)

In this order, we accept for filing, without suspension or hearing, Boston Edison Company's (Boston Edison) revised formula rate effective June 1, 2000.

Background

On March 31, 2000, Boston Edison submitted for filing a proposal to revise its formula rate under its OATT from a formula based on historical costs to a formula based on estimated costs for the billing period.[1] Boston Edison also proposes an annual true-up of its estimated transmission costs that is based on actual costs. Boston Edison seeks an effective date of June 1, 2000.

Boston Edison says that the restructuring of the electric power market in Massachusetts dictates that Boston Edison modify and construct additional transmission facilities and that a formula rate based on historical costs will not be representative of its actual costs in the years 2000 and 2001.[2]

---

[1]To develop the estimates, Boston Edison will add to its prior year costs the costs of new investments that are planned during the billing year. The revised formula results in an increase of $4.9 million in Boston Edison's annual transmission revenue requirement based on the billing year beginning June 1, 2000.

[2]The billing period is June 1, 2000, through May 31, 2001.

Notice and Interventions

Notice of Boston Edison's filing was published in the Federal Register, 65 Fed. Reg. 20,448 (2000), with comments, protests and motions to intervene due on or before April 21, 2000.

Motions to Intervene and Protests

Timely motions to intervene were filed by New England Power Company and jointly by FPL Energy, LLC and Northeast Energy Associates, LP. Braintree Electric Light Department and Reading Municipal Light Department (Braintree and Reading) jointly filed a timely motion to intervene and comments. Braintree and Reading's comments describe a settlement agreement between themselves and Boston Edison, in Docket Nos. ER99-978-000 and EL99-31-000, which provides that Boston Edison may not charge them transmission rates that exceed a rate cap included in the settlement.[3] Based on a clarification by Boston Edison that its proposed recovery of transmission costs will not exceed the rate cap in the settlement, Braintree and Reading do not object to Boston Edison's filing.[4]

The Town of Norwood, Massachusetts, (Norwood) and Concord Municipal Light Plant (Concord) each filed a timely motion to intervene and protest. On May 11, 2000, Boston Edison filed an answer to the protests of Norwood and Concord.

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[3]The settlement agreement (approved by the Commission in Boston Edison Company, 90 FERC ¶ 61,071 (2000)), provides for specific caps on the amounts Boston Edison may charge its PTF-connected transmission customers under Schedule 9 of its OATT during each year of the balance of the initial stage of the NEPOOL Transition Period. The PTF-connected customers are those transmission customers interconnected with the Boston Edison local transmission system at voltages of 69 kV or above.

[4]Braintree and Reading state that they have assurances from Boston Edison's counsel that Boston Edison will provide a written confirmation that its transmission bills will not exceed the agreed-on rate cap. Boston Edison's answer confirms the representation reported in the intervention of Braintree and Reading that Boston Edison will not bill its PTF-connected customers any amounts in excess of the rate caps established under the settlement agreement.

Discussion

Procedural Matters

Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (1999), the timely motions to intervene of the intervenors serve to make them parties to this proceeding. In addition, pursuant to Rule 213 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213 (1999), we will accept Boston Edison's answer because it aids in our understanding of this application.

Boston Edison's Proposed Revisions

Abbreviated Rate Filing Requirements

Norwood argues that the filing should be rejected because it is an application for a rate increase that does not comply with the provisions of section 205(a) of the Federal Power Act,[5] or the Commission's regulations relating to the data required to justify a rate increase.[6] Norwood further argues that the revised tariff would increase rates by $4,918,138 and that such an increase does not qualify for an abbreviated rate filing under our filing regulations at 18 C.F.R. § 35.13(a)(2). Norwood states that Boston Edison is required to file both Period I and Period II data.

Commission Conclusion

Section 35.13(a)(2) of the Commission's regulations provides, in relevant part, that applications for changes in rate schedules qualify for abbreviated filing requirements, regardless of customer consent, if the proposed increase for the test period is less than or equal to $200,000. Norwood states that Boston Edison's proposed tariff revisions result in an annual rate increase of $4.9 million and thus do not qualify for an abbreviated rate filing. However, Norwood focuses on the change in the annual revenue requirement, whereas the increase in jurisdictional transmission rates under the revised formula rate, taking into account the settlement rate cap, results in a proposed increase in jurisdictional rates of only $62,566. Therefore, neither Period I nor Period II data is required.

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[5]See 16 U.S.C.§ 824(d)(FPA).

[6]See 18 C.F.R.§ 35.13(a)(1999).

Formula Rates

Concord points out that, because a formula rate goes into effect automatically without scrutiny by the Commission, the Commission should not allow Boston Edison to collect transmission rates based on estimates. However, if the Commission does allow the use of estimates, Concord requests that Boston Edison be required to make an informational filing 90 days prior to the effective date of new rates that would detail how those rates were computed. Concord argues that such a filing requirement would allow customers to challenge any new estimates and would place the burden of supporting estimates on Boston Edison.

Norwood argues that Boston Edison's proposal to base rates on estimates of future costs is inconsistent with the traditional cost of service regulations required by the Commission under section 205 of the FPA. Norwood is concerned that Boston Edison will recompute the formula and revise rates on a monthly basis, making it impossible for customers to predict what their transmission costs will be in the future. Norwood warns that Boston Edison's rates would change without review by the Commission and that this might lead Boston Edison to overestimate its transmission costs.

Commission Conclusion

We will direct Boston Edison to submit a customer rate notification before changing its estimates of transmission costs to allow Boston Edison's customers an opportunity to review the revised cost estimates before they go into effect.[7] We will require that the customer rate notifications be sent to customers at least 60 days prior to the proposed effective date for such revisions.

Adequacy of Proposed True-Up Mechanism

Concord argues that Boston Edison's current rate formula assures that the rates will not include excessive charges because the rates are based on actual incurred costs. Concord adds that a customer's competitive opportunities may well be gone by the time projected rates are trued-up as proposed. Concord argues the fact that it will receive

[7]This approach also adequately addresses the concerns raised by Norwood.

refunds for excessive estimates at the true up stage, does not prevent the inflation of retail rates based on excessive charges in the interim.

Commission Conclusion

Boston Edison's revised rate formula with a true-up adjustment should create estimates that are more representative of the costs in the current period. However, in this case, Boston Edison reports that $1.3 million of the revised revenue requirement is estimated to be recovered from wholesale customers, but the revised requirement does not appear to reflect the applicable settlement rate cap of $1.1 million for the billing period beginning June 1, 2000.[8] We direct Boston Edison to incorporate the appropriate settlement rate caps in the estimates. Of course, Boston Edison's annual true-up adjustments should also reflect the settlement caps.

The annual true-up adjustments should reflect the actual transmission costs incurred by Boston Edison. For example, Boston Edison is required to account for new capital additions in the same manner as it has accounted for the capital investments currently reflected in its rates, by recomputing the formula based on the formula rate components previously approved by the Commission. In addition, annual true-up adjustments that result in refunds to customers for overestimations of costs must include interest calculated in accordance with the Commission's regulations.[9]

Proposed Rates

Norwood argues that Boston Edison has not shown that its revised tariff and the resulting increased rates would result in rates that are just and reasonable. In addition, Norwood argues that Boston Edison's proposal to switch to a formula rate for the derivation of the revenue requirement, as well as for the derivation of the Schedule I costs for Scheduling, System Control and Dispatch Service, pose substantial issues that justify setting the matter for hearing.

---

[8]Boston Edison's Attachment 5, Column (D), reports the total revenue requirement for retail and wholesale customers of $23,730,592 less the retail revenue requirement of $22,438,011 results in a wholesale revenue requirement of $1,292,581, which is above the $1,100,000 settlement cap.

[9]<u>See</u> 18 C.F.R.§ 35.19(a)(1999).

Commission Conclusion

Boston Edison's current OATT already authorizes the use of a formula rate. Thus, the sole issue is the reasonableness of Boston Edison's proposed method for estimating transmission costs to be effective on June 1, 2000, as requested.

Our preliminary analysis indicates that the proposed formula rate, with a true-up adjustment, as modified above, appears to be just and reasonable and has not been shown to be unjust, unreasonable, unduly discriminatory or preferential, or otherwise excessive. Accordingly, the Commission will accept for filing Boston Edison's proposed formula rate, as modified, without suspension or hearing, to be effective on June 1, 2000, as requested.

The Commission orders:

(A) Boston Edison's proposed formula rate is hereby accepted for filing, as modified, without suspension or hearing, to become effective on June 1, 2000, as discussed in the body of this order.

(B) Boston Edison is hereby directed to submit customer rate notifications to its customers, at least 60 days prior to the proposed effective date of any formula rate change based on revisions to its estimated transmission costs, as discussed in the body of this order.

(C) Boston Edison is hereby informed of the rate schedule designations listed in the following attachment.

By the Commission.

(S E A L)

Linwood A. Watson, Jr.,
Acting Secretary.

ATTACHMENT

Boston Edison Company
Docket No. ER00-2065-000
Rate Schedule Designations

	Designation	Description
(1)	Original Sheet Nos. 9A, 21A, 31A, and 115A under FERC Electric Tariff, Original Volume No. 8	Revised tariff sheets to change estimates of transmission costs in formula rate
(2)	Second Revised Sheet Nos. 31 and 115 under FERC Electric Tariff, Original Volume No. 8 (Supersedes First Revised Sheet Nos. 31 and 115)	Revised tariff sheets
(3)	Third Revised Sheet Nos. 1 through 9 and 21 under FERC Electric Tariff, Original Volume No. 8 (Supersedes Second Revised Sheet Nos. 1 through 9 and 21)	Revised tariff sheets
(4)	Fourth Revised Sheet Nos. 123 and 210 under FERC Electric Tariff, Original Volume No. 8 (Supersedes Third Revises Sheet Nos. 123 and 210)	Revised tariff sheets

Information Request DTE-3-9

Since it first unbundled its rates has the Company changed the method it uses to determine its transmission rates? If yes, please explain each change and why each change was made.

Response

No.

Information Request DTE-3-10

Since it first unbundled its rates has the Company changed the categories of costs that it includes in its transmission rates? If yes, please explain each change and why each change was made.

Response

Yes, the Company's categories of cost have changed from the time of unbundling due to the bifurcation of the NEPOOL Transmission System into a Regional and Local transmission system that are governed by different tariffs. Under the historical regime, most regional and all local uses of the NEPOOL Transmission System had to be obtained and paid for under the individual tariffs of the POOL Participants. Thus, at the time of unbundling all of the transmission costs assessed to the retail customers were charged solely through the Company's OATT. Under the new regime, regional network uses and associated costs of the NEPOOL transmission system are provided under the NEPOOL Open Access Transmission Tariff and the ISO-NE Tariff, while Local Network Service and associated costs are provided under the Company's Local Open Access Transmission Tariff. As such, the transmission costs applicable to the Company's retail customers in today's regime are assessed through the three tariffs.

Please see the response to Information Request DTE 3-6 for the description of each cost category for Columns A through P for Exhibit BEC-JFL-3. The costs shown recognize the different costs assessed by the three tariffs as opposed to the transmission costs developed under the Company's OATT at the time of unbundling.

Information Request DTE-3-11

Please provide a description of the transmission assets owned by Boston Edison that are categorized as PTF and those that are categorized as non-PTF. Include the book value as of December 2002.

Response

Generally, Pool Transmission Facilities ("PTF") under the Restated NEPOOL Agreement, are transmission facilities rated at 69 kilovolts ("kv") or above that are required to allow energy from significant power sources to move freely on the New England Transmission network.

Boston Edison's transmission assets that are designated as PTF consist of all its looped transmission lines rated at 115 kv and above that contribute to the parallel capability to the transmission network. Most of Boston Edison's 115kv lines are PTF- related while all of its 230 kv and 345 kv lines are PTF.

Boston Edison also owns transmission assets in terminal facilities that are required to interconnect the lines and which, therefore, constitute PTF. The terminal facilities include substation facilities such as transformers, circuit breakers, disconnects and airbreaks, bus conductors, protection equipment and other related facilities.

Boston Edison's Non-PTF facilities are primarily 115 kv lines that are 1) lines that are radial in nature which serve local load and 2) those lines that normally operate open.

Boston Edison's terminal facilities that interconnect only Non-PTF lines are classified as Non-PTF.

BECO also has some multi-use terminal facilities that interconnect both PTF and Non-PTF lines. In these cases the cost of the terminal facility was allocated to PTF and Non-PTF in accordance with NABS12 procedures set forth under the NEPOOL Agreement.

Boston Edison also has Right of Way costs that are classified as PTF and Non-PTF on the basis of the current PTF rules in effect.

Boston Edison does not have the book value determination for the year 2002. For 2001, the book value of PTF investment was $382,097,464 and the book value of Non-PTF investment was $96,400,069.

Information Request DTE-3-12

Please provide a listing of all transmission rate proceedings outside of those before the DTE, that affect of have affected the Company's 1998 through 2003 transmission expenses. Include the docket number, filing date, date of final order, and a brief summary of the decision.

Response

The transmission rate proceedings that have affected the Company's 1998 through 2003 transmission expenses are as follows:

In Docket No. OA96-70-000, FERC approved of a comprehensive settlement of all issues with respect to Boston Edison's Open Access Transmission Tariff ("OATT") bringing it into compliance with Order No. 888. The Settlement also established the Annual Transmission Revenue Requirement for Network Transmission Service at $40,000,000.

The filing date and the FERC Order issuance date of Docket No. OA96-70-000 was January 11, 1999 and April 29,1999, respectively.

In Docket No. ER99-978-000, FERC approved a settlement that resolved all disputes and controversies regarding transmission rates. The settlement included a formula rate structure in assessing the costs associated with transmission service under Boston Edison's OATT.

The filing date and the FERC Order issuance date of Docket No. ER99-978-000 was September 17, 1999 and January 28, 2000, respectively.

In Docket ER00-2065-000, FERC approved a filing by Boston Edison to revise its formula rate under its OATT from a formula-based on historical costs to a formula based on estimated costs for the billing period subject to an annual true-up once actual costs were known.

The filing date and the FERC Order issuance date of Docket No. ER00-2065-000 was March 31, 2000 and May 31, 2000, respectively.

Information Request DTE-3-13

How does the Company incorporate any billing adjustments and corrections in the reconciliation of its transmission revenues and expenses? Please provide the details of each adjustment in excess of $5,000.

Response

The Company's current Open Access Transmission Tariff ("OATT"), which became effective June 1, 2000, provides for the Company to forecast revenue requirements for the period June – May. There is a true-up provision to calculate actual costs for each year and make adjustments to the billings for that year.

Copies of the adjustments made for the periods June 1, 2000 – December 31, 2000 and January 1, 2001 – December 31, 2001 are shown in Attachment DTE 3-13.

ATTACHMENT DTE 3-13
PAGE 1 OF 2

BECo

2000 Transmission Revenue Requirements - True -up for June - Dec PER Tariff

Monthly Rev Reqm't = Annual Rev Reqm't (below) divided by 12

	Original	True-up	Diff	Retail Load Ratio %	Adjustment due (Retail)/ BECo
Jan					
Feb					
Mar					
Apr					
May					
June	4,608,387	4,547,345	(61,043)	83.70%	(51,093)
July	4,608,387	4,547,345	(61,043)	83.77%	(51,135)
Aug	4,608,387	4,547,345	(61,043)	83.83%	(51,172)
Sept	4,608,387	4,547,345	(61,043)	83.76%	(51,129)
Oct	4,608,387	4,547,345	(61,043)	83.80%	(51,154)
Nov	4,608,387	4,547,345	(61,043)	83.81%	(51,160)
Dec	4,608,387	4,547,345	(61,043)	83.83%	(51,172)
	32,258,710	31,831,412	(427,298)		(358,015)

Annual Rev Req:

Estimate	55,300,646
True-up	54,568,135

BECo

2001 Transmission Revenue Requirements - True -up for Jan - Dec, Per Tariff

Monthly Rev Reqm't = Annual Rev Reqm't (below) divided by 12

	Original	True-up	Diff	Retail Load Ratio %	Adjustment due (Retail)/ BECo
Jan	4,812,384	5,012,518	200,134	83.83%	167,772
Feb	4,812,384	5,012,518	200,134	83.92%	167,952
Mar	4,812,384	5,012,518	200,134	83.94%	167,992
Apr	4,812,384	5,012,518	200,134	84.00%	168,112
May	4,812,384	5,012,518	200,134	84.06%	168,232
June	4,812,384	5,012,518	200,134	84.07%	168,252
July	4,656,605	5,012,518	355,913	84.02%	299,038
Aug	4,656,605	5,012,518	355,913	83.95%	298,789
Sept	4,656,605	5,012,518	355,913	83.99%	298,931
Oct	4,656,605	5,012,518	355,913	84.02%	299,038
Nov	4,656,605	5,012,518	355,913	84.04%	299,109
Dec	4,656,605	5,012,518	355,913	84.04%	299,109
	56,813,934	60,150,212	3,336,278		2,802,327

Est Annual Rev Req:

Jan - June	57,748,310
July - Dec	55,879,260
Actual Rev Req:	60,150,212

Information Request DTE-3-14

Does the Company provide any transmission services to customers other than its retail distribution customers? If yes, explain the services provided and how the rates for these services are set. Include the expenses and revenues for these services for the period March 1998 through December 2002. How does the Company account for these revenues and expenses on its books and in the transmission service reconciliation?

Response

Yes, the Company provides transmission service to customers other than its retail distribution customers. The service provided is Local Network Service ("LNS"). The LNS revenue requirement is calculated pursuant to the Company's local Open Access Transmission Tariff ("OATT") that was approved by the FERC. Each customer taking service under the OATT, including retail distribution customers, is charged its load ratio share of the revenue requirement credited for revenues received by the Company for Regional Network Service provided under the NEPOOL OATT.

This revenue requirement was $24.6 million for March through December 1998, $26.1 million for 1999, $20.4 million in 2000, $18.1 million in 2001 and estimated at $10.2 million for 2002. The revenues received from customers other than retail customers, calculated pursuant to the NEPOOL OATT for customers connected to the Company's Pool Transmission Facilities and pursuant to the settlement in the Company's OATT (Docket Nos. ER99-978-000 and EL99-31-000), were approximately $4.8 million, $5.0 million, 2.1 million, $0.6 million and $0.2 million, for the same respective periods.